

# DSM shareholder incentives: recent designs and economic theory

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Received October 1996; accepted December 1997

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## Abstract

U.S. utility DSM shareholder incentives represent a unique form of targeted incentive regulation designed to motivate utilities to achieve specific energy-efficiency objectives. Through a review of recent DSM shareholder incentive designs and earnings for 10 U.S. utilities, we conclude that the mechanisms could be improved by harnessing their incentive powers more deliberately to ensure better alignment of regulatory objectives and utility financial self-interest. Better alignment reduces adversarial confrontation and eliminates the need for regulatory micro-management. We make five specific recommendations: (1) apply shared-savings incentives to DSM resource programs (2) use markup incentives for individual programs only when net benefits are difficult to measure, but are known to be positive (3) set expected incentive payments based on covering a utility's 'hidden costs,' which include some transitional management and risk-adjusted opportunity costs (4) use higher marginal incentives rates than are currently found in practice, but limit total incentive payments by adding a fixed charge (5) mitigate risks to regulators and utilities by lowering marginal incentive rates at high and low performance levels. As regulators and utilities contemplate new forms of regulation for a restructured electricity industry, the lessons from the U.S. experience with DSM shareholder incentives are readily generalizable: Be explicit about the regulatory objective when considering multiple objectives, look broadly at alternatives that have the potential to meet these objectives without compromising the incentive properties of the mechanisms. © 1998 Elsevier Science Ltd. All rights reserved.

*Keywords:* Energy efficiency; Incentive regulation

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## 1. Introduction

U.S. utility demand-side management (DSM) shareholder incentives represent a unique form of targeted incentive regulation designed to motivate utilities to achieve specific energy-efficiency objectives. Most observers agree that the availability of these incentives largely explains the dramatic increase in U.S. utility DSM spending in the early 1990s (Nadel and Jordan, 1992). However, with few exceptions, the DSM shareholder incentive mechanisms adopted for U.S. utilities were developed case by case. This paper reviews a sam-

ple of these approaches and argues that their incentive properties could be improved through modifications that better align these incentives with the stated regulatory objective(s). We believe the lessons learned for improving DSM shareholder incentive designs are applicable both to future forms of incentive regulation for DSM as well as to other targeted forms of incentive regulation for the utility industry.

Currently, the U.S. electricity industry is undergoing a fundamental restructuring that will change the ways in which the former goals of integrated resource planning are pursued. That is, many agree that restructuring, by itself, will not eliminate *all* of the historic justifications for energy-efficiency activities, which include the environmental externalities uniquely associated with the generation of electricity (Eto et al., 1996a). However, many also agree that restructuring will eliminate the historic rationale for *utility-delivery* of energy-efficiency activities because restructuring eliminates utilities' obligation to plan and acquire resources — including acquisition of cost-effective energy-efficiency measures — on behalf of captive customers (Eto and Hirst, 1996).

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*Abbreviations:* APS = Arizona Public Service; Con Edison = Consolidated Edison of New York; IRP = Integrated Resource Planning; JCP&L = Jersey Central Power and Light; MECo = Massachusetts Electric Company; Midwest = Midwest Power; NSP = Northern States Power; NYSEG = New York State Electric and Gas; PG&E = Pacific Gas and Electric; PGE = Portland General Electric; RB = Ratebase; ROE = Return on Equity; SCE = Southern California Edison; TRC = Total Resource Cost; UC = Utility Cost

In view of these considerations, many states furthest along in restructuring have made explicit provisions to continue ratepayer funding for energy efficiency and other public purpose activities, typically through the imposition of a surcharge on electricity use that is paid by all users (Eto et al., 1996a). Both utility and non-utility providers have been awarded or are being considered for franchises to continue administering energy-efficiency programs with these funds. Ultimate authority for the funds remains with state regulatory commissions. Consequently, targeted incentives to reward superior performance in delivering energy-efficiency programs remains an important topic for regulatory policy. In particular, we believe the original integrated resource planning (IRP) rationale for these programs — to acquire energy efficiency as a resource whenever it costs less than the equivalent supply side resources it replaces — will remain an important objective for these programs.

Our examination of DSM shareholder incentives is based on two major assumptions. We start with the assumption that the overriding regulatory objective is the maximization of social value or societal net benefits, which is consistent with the rationale for integrated resource planning (Krause and Eto, 1988). This assumption is critical to our review because we believe that the efficacy of incentives can only be analyzed with explicit reference to particular regulatory objectives. In several instances, we identify interactions between maximization of societal benefits and other regulatory objectives. Our purpose is not to question the legitimacy of any objective, but to indicate where they may involve trade-offs, and where they are complementary.

Our second major assumption is that disincentives or hidden costs are associated with pursuit of DSM net benefits by regulated entities, such as utilities, and that these costs must be overcome by a fair shareholder incentive (Nadel et al., 1992). This now conventional perspective does not mean that DSM shareholder incentives are the only way to overcome these disincentives, but it does mean that the success of DSM shareholder incentives as a regulatory strategy depends on how well disincentives or hidden costs are addressed. We discuss the ways that incentives should change as regulated agents (which for convenience, we will refer to as utilities in the remainder of this article) become familiar with acquiring DSM resources.

This paper is organized around five sections following this introduction. In Section 2, we describe ten recent DSM shareholder incentives and introduce a typology of design features that serves to organize our analysis. In Section 3, we begin this analysis by categorizing the incentives according to the performance they reward. We argue that the shared-savings incentive design is superior for achieving the regulatory objective of maximizing net benefits. In Section 4, we review the size of the incentive payments made to utilities and describe the hidden cost

and incentive regulation principles associated with establishing them. In Section 5, we compare marginal incentive rates and argue that they represent a powerful, yet currently underutilized, tool for communicating regulatory priorities. In Section 6, we illustrate the role of earnings and penalty caps for mitigating risks to the regulator and utility, respectively. Section 7 summarizes our recommendations for improving DSM shareholder incentive designs.

## 2. Ten U.S. utility DSM shareholder incentives

To ground our analysis of DSM shareholder incentives, we review recent incentive designs and performance for ten U.S. utilities. Table 1 compares 1992 DSM spending and DSM shareholder incentives for each utility. DSM spending by the utilities ranged from \$3.4 to \$224.1 million in 1992. Expressed as a percentage of total utility revenue, the range is from 0.2 percent to 3.2 percent. This range is consistent with the current range of U.S. utility spending on DSM, which is to say that few utilities are spending more than 3 percent on DSM although many, generally smaller utilities are spending less than 0.2 percent.

The incentive payments received by the utilities in 1992 range from \$0.3 to \$44.9 million. Expressed as a percentage of net operating income, the range of payments is 0.03 percent to 6.2 percent. The range is weighted more heavily toward the smaller values.<sup>1</sup>

Table 2 summarizes the lost revenue recovery mechanisms used by regulators more recently for each utility. Gallagher (1991) has shown that accounting for the existence of these mechanisms is critical for understanding the net effect of a DSM shareholder incentive. For the most part, the DSM shareholder incentives we examine address lost revenues either through lost revenue or decoupling mechanisms.<sup>2</sup> This allows us to compare DSM incentive payments across utilities without specific attention to otherwise offsetting influences arising from under-recovery of program costs or lost revenues.<sup>3</sup>

Fig. 1 summarizes the generic design features of DSM shareholder incentive mechanisms. The first issue, which is reflected in the basic design of the incentive mechanisms, is the performance being rewarded (see Section 3). In Fig. 1, this is the quantity on the horizontal axis.

<sup>1</sup> See also Nadel and Jordan (1992) for additional approaches to examining the relationship between shareholder incentives and various measures of DSM program size.

<sup>2</sup> See Eto et al. (1997) for a discussion of decoupling.

<sup>3</sup> Concern remains regarding the lack of symmetry in the incentive properties of net lost revenue adjustments (see, for example, Moskovitz et al., 1992); in this article we do not question their ability to remove the disincentives associated with lost sales resulting from successful conservation programs.

Table 1  
Utility DSM shareholder incentives – 1992 program year

Utility	State	Total DSM expenditures* \$millions)	DSM expenditure/electric operating revenue**	Shareholder incentives before taxes <sup>†</sup> (\$millions)	Incentives/total DSM expenditures	Incentives/net operating income <sup>††</sup>
Arizona Public Service (APS)	AZ	3.4	0.2%	0.3	8.8%	0.03%
Pacific Gas & Electric (PG&E)	CA	224.1	2.9%	44.9	20.0%	1.7%
Southern California Edison (SCE)	CA	113.4	1.5%	2.1	1.9%	0.1%
Midwest Power (Midwest)	IA	19.1	3.1%	1.5	7.6%	0.8%
Massachusetts Electric Co. (MECo)	MA	45.5	3.2%	7.6	16.0%	6.2%
Northern States Power (NSP)	MN	25.4	1.5%	0.8	3.1%	0.2%
Jersey Central Power & Light (JCP&L)	NJ	21.7	1.2%	4.2	19.4%	0.7%
Consolidated Edison (Con Edison)	NY	117.0	2.4%	28.8	24.6%	1.1%
New York State Electric & Gas (NYSEG)	NY	40.6	2.8%	16.1	39.7%	2.6%
Portland General Electric (PGE)	OR	10.7	1.2%	10.1	94.3%	3.0%

\* Total DSM expenditures include the utilities' entire DSM program expenditures, including evaluation costs, as well as expenditures on load management and load retention programs and programs for which the utility receives no incentive.

\*\* Electric utility operating revenue was obtained from the annual financial filings of the utility with the Federal Energy Regulatory Commission (FERC), as reported by the Energy Information Administration (EIA, 1993).

<sup>†</sup> Shareholder incentives represent *before tax* incentive payments to the utility. The incentive payments for APS and PGE include the net present value of the expected incentive payment stream. The incentive payment to Midwest applies to the 1990–1992 period and reflects the Commission's recent downward adjustment. The incentive payments and expenditures for JCP&L apply to the 1993 program year because JCP&L had little DSM activity in 1992. The incentive payment for PG&E has been adjusted to reflect adjustments made by the CPUC that are applicable to the 1992 program year.

<sup>††</sup> Net Operating Income was obtained from EIA (1993) and was calculated by adding back in all tax items to the net electric utility operating income.

Table 2  
Utility DSM shareholder incentive mechanisms – 1994 program year

Utility	State	DSM shareholder incentive mechanism(s)	Lost revenue recovery mechanism
Arizona Public Service (APS)	AZ	Bonus	Yes
Pacific Gas & Electric (PG&E)	CA	Shared savings & markup	Decoupling
Southern California Edison (SCE)	CA	Shared savings & markup	Decoupling
Midwest Power (Midwest)	IA	Shared savings	Yes
Massachusetts Electric Co. (MECo)	MA	Shared savings/bonus hybrid	Decoupling <sup>‡</sup>
Northern States Power (NSP)	MN	Bonus	Partial
Jersey Central Power & Light (JCP&L)	NJ	Shared savings	Yes
Consolidated Edison (Con Edison)	NY	Shared savings	Yes
New York State Electric & Gas (NYSEG)	NY	Shared savings	Yes
Portland General Electric (PGE)	OR	Shared savings/bonus hybrid	Yes

<sup>‡</sup> Although the Massachusetts DPU provides no treatment of lost revenues for MECo, MECo through its generating affiliate, New England Power System, is made whole for lost revenues through rate cases at FERC, which has the same effect as decoupling (see Eto et al., 1992).

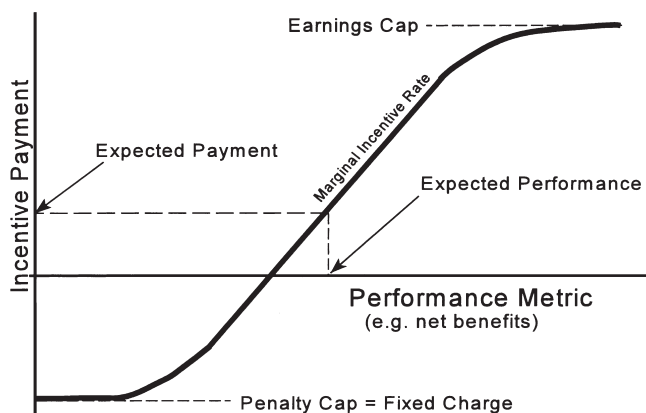


Fig. 1. Structural elements of a DSM shareholder incentive mechanism.

The second issue is the size of the incentive payment for a given level of performance (see Section 4). This is a point on the vertical axis associated with a given level of performance. The third issue is the marginal incentive rate or the slope of the incentive payment curve as a function of changes in performance (see Section 5). The fourth issue is the use of earnings and penalty caps, which we represent as a flattening of the incentive payment curve at high and low levels of performance (see Section 6).

### 3. Evaluating overall designs for DSM shareholder incentives

Table 2 summarizes basic design features of 10 utility DSM shareholder incentives for the 1994 program year. The designs fall into three basic categories: bonus, savings, and markup incentive mechanisms.<sup>4</sup> We define these relationships formally, using the following equations (Stoft and Gilbert, 1994):

Bonus:  $I = \lambda Q - F$ ,

Shared Savings:  $I = \lambda (AQ - C_u - C_p) - F$

Markup:  $I = \lambda C_u - F$

where,

$I$	incentive payment;
$\lambda$	incentive rate;
$A$	per-unit avoided energy and capacity costs;

<sup>4</sup> In addition to these incentive designs, some utilities have adopted return on equity (ROE) adjustment mechanisms and ratebase (RB) bonus mechanisms. We believe these incentives fall into the three categories discussed above. RB bonus mechanisms adjust the allowed rate of return on ratebased DSM program expenditures and ROE adjustments work in a similar fashion, allowing increases in a utility's ROE. These two mechanisms fall into the 'bonus/unit' category when the bonus depends upon the amount of energy saved and into the markup and shared savings categories when the incentive payment depends upon expenditures or net benefits, respectively.

$Q$

$C_u$

$C_p$

$F$

quantity of energy and capacity saved;  
utility program costs;  
participant costs; and  
fixed payment.

The fixed payment term, which sets the magnitude of the incentive payment at an expected level or performance and may result in penalties if the utility fails to undertake a DSM program, merits some explanation. For example, if a utility had a bonus incentive mechanism with  $\lambda$  equal to 1¢ per kilowatt hour and  $F$  equal to \$1 million (i.e.,  $I = 1¢/\text{kWh} * Q - \$1 \text{ million}$ ), then the utility would incur penalties of \$1 million if no energy is saved. On the other hand, the utility would break even if it saved 100 million kWh and would earn \$1 million if it saved 200 million kWh. In our survey, we only found shared savings mechanisms with fixed payment terms, but, in principle, they could also be used in conjunction with both the bonus and markup mechanisms.

Bonus mechanisms reward utility shareholders on a per-unit basis for energy and demand savings. For example, Arizona Public Service (APS) receives a reward of about \$104 per kilowatt (kW) saved. Bonus mechanisms, which are somewhat less common than shared savings mechanisms, have been adopted by utilities in six states (Reid et al., 1993).

The shared-savings incentive mechanism provides utility shareholders with a share of the energy savings benefits or 'net benefits.' For example, Consolidated Edison (Con Edison) provides shareholders with 23 percent (before tax) of the net benefits achieved for its 1993 and 1994 DSM programs. Shared-savings incentive mechanisms are the most common and have been adopted by utilities in 16 states.

Finally, markup mechanisms provide a markup on DSM program expenditures, generally varying from five to ten percent. Markup mechanisms frequently apply to a subset of utility programs where energy savings benefits are particularly difficult to measure (e.g., information programs) or where the programs are undertaken based on equity rather than efficiency considerations (e.g., low-income weatherization). For example, Pacific Gas and Electric (PG&E) receives a five percent markup on its information and audit programs, but also receives shared-savings incentives for its 'resource-based' DSM programs.

Two utilities (Massachusetts Electric Company or MECo and Portland General Electric or PGE) use hybrid incentives, which combine elements of several of these incentive types into a single formula. MECo's hybrid incentive combines a bonus with a shared-savings incentive mechanism. PGE's hybrid incentive combines a bonus and two forms of shared savings, one of which provides an incentive to minimize rate impacts.



### 3.1. Use of bonus mechanisms requires TRC constraints to ensure cost effectiveness

From the standpoint of acquiring energy efficiency cost effectively, the purpose of an incentive mechanism should be to maximize the net benefits from the DSM program, not just energy or capacity savings. To illustrate this point and its importance for the design of incentives, consider the possible results of a hypothetical bonus mechanism that rewards energy savings.<sup>5</sup> Typically, as with most incentive programs, the DSM program has an expenditure cap. For this example, assume that the bonus is 1¢/kWh and that the cost of supply is 8¢/kWh. Also assume that the DSM expenditure cap is high enough and that inducing energy savings is difficult enough that, after spending all but the last \$1 million of its budget the utility has been reduced to installing quite inefficient DSM measures, which cost the utility 20¢/kWh. What will the utility do? Because most commissions reimburse utilities for program costs, the utility knows that for each 20¢ it spends, it will receive a 20¢ reimbursement plus a 1¢ reward for the saved kWh. Thus, even though the DSM program is wasting 12¢/kWh (20¢ – 8¢), the utility will spend its last \$1 million on these inefficient measures in order to earn the \$50 000 reward. The net result is \$600 000 of waste imposed on ratepayers followed by a \$50 000 transfer payment from ratepayers to utility stockholders as a reward.

In fairness, many bonus mechanisms require that the individual programs or measures pass a Total Resource Cost (TRC) test before they are implemented.<sup>6</sup> This requirement helps to avoid the situations such as the one described in our example, but it does not prevent them entirely. This is because a program with a marginal cost of 20¢/kWh may still pass a TRC test, since this test is based on averages. Thus, while the average cost of conserved energy for a program may be low, the cost for the marginal DSM measure may be quite high. As we will discuss, a utility would have an incentive to avoid these marginal measures with a shared savings program, but not with a bonus program.

TRC tests could take into account marginal net benefits, and public utility commissions could require that programs under a bonus mechanism each be carried out to the point where the marginal net benefits were equal across programs. But this just turns a bonus mechanism into a shared savings mechanism. The advantage of the bonus is that it is simple, but by forcing a careful compu-

tation of the TRC test one has reintroduced all of the complexity that bonus mechanisms were meant to avoid.

However, bonus mechanisms do not perform poorly when the utility has plenty of ‘cheap’ DSM measures (i.e., measures that cost less than the avoided cost benefits). In these instances, the bonus mechanisms motivate suboptimal behavior, but they do not necessarily induce behavior that is detrimental to the public good. They simply cause the utility to maximize benefits minus utility cost, instead of total benefits minus social cost.<sup>7</sup> This will tend to bias the utility towards programs with low utility costs. Of course, these programs may well also have high participant costs and, thus, high social costs. It is these participant costs that bonus mechanisms fail to induce the utility to avoid. Thus, with a bonus mechanism and plenty of ‘cheap’ DSM measures, the utility would not generate negative net benefits (from a utility cost perspective), but it would have no incentive to generate the greatest positive social benefits.

### 3.2. Shared-savings incentive mechanisms provide superior incentives, when properly defined

We advocate the use of shared-savings incentive mechanisms because they can directly ensure consistency between the regulatory objective of maximizing net social benefits and the financial interests of the utility (Eto et al., 1992). We observe, however, that this consistency is not achieved automatically. The regulatory objective can be compromised both by incomplete specification of net benefits (for example, specifying net benefits using the utility costs, rather than the total resource costs) and also by the common practice of placing spending or earnings caps on individual utility DSM programs. One can demonstrate that a shared-savings incentive mechanism with net benefits based only on utility costs, coupled with a modest spending cap, is, in fact, a bonus incentive mechanism in disguise (Stoft et al., 1995). That is, it provides the utility with an incentive to maximize energy and capacity savings, not net societal benefits.

In practice, net benefits are defined differently, and may sometimes be difficult to measure. Table 3 summarizes the components of net benefits for eight utilities with shared-savings incentives. Some utilities include environmental adders in their calculation of benefits; others do not. Estimating the cost of environmental externalities is difficult, as described extensively in the literature.<sup>8</sup> Some utilities routinely exclude monitoring and evaluation costs because they are incurred after a program has finished. Incremental customer costs are

<sup>5</sup> This example is an exaggeration to illustrate the potential problems associated with bonus mechanisms. It ignores the participant’s perspective, which would affect the ability of the utility to market such a program.

<sup>6</sup> The TRC test is defined as the avoided cost benefits less the utility program costs and incremental participant costs.

<sup>7</sup> In fact, since utilities rarely distinguish between on-peak and off-peak kWh in bonus programs, they are probably optimizing kWh per utility dollar spent rather than benefit per utility dollar spent.

<sup>8</sup> See, for example, Ottinger et al. (1990).

Table 3  
Definitions of net benefits

Utility	Benefits		Utility administration costs	Utility evaluation costs	Costs		Incremental participant costs
	Avoided costs	Externality adder			Utility rebate costs		
PG&E	x		x		partial		partial
SCE	x		x		partial		partial
Midwest	x	x	x	x	x		x
MECo	x	x	x		x		
JCP&L	x	x	x	x	x		
Con Edison	x	x	x	x	x		
NYSEG	x	x	x	x	x		
PGE	x		x		partial		partial

frequently omitted because they are hard to measure or estimate.

Academic economists and DSM program evaluators have begun to discuss a variety of additional costs and benefits usually omitted from net benefit calculations.<sup>9</sup> These costs (such as consumer disutility) and benefits (such as market transformation) are controversial, in part, because they are quite difficult, if not impossible, to measure. Not surprisingly, they have not been included in the specification of net benefits for current shared-savings incentives.

Omission of relevant costs or benefits from the definition of net benefits can, in principle, skew a utility's private interest away from the social good. In the case of environmental externalities, the effects of omission could be significant, if they are not addressed through other means. In the case of monitoring and evaluation costs, which tend to be a modest percentage of total societal costs, the effects may be less significant.<sup>10</sup>

### 3.3. Why the markup mechanism is dangerous, but sometimes appropriate

The need to introduce additional conditions to ensure bonuses are cost effective also argues against the use of markup mechanisms, which simply reward spending. That is, the link between spending and net social benefit is even more tenuous than it is between energy savings and net social benefit. There are, however, instances when the use of markups may be justified.

Markups can be appropriate when the regulator is able to make an unbiased estimate of the net benefits of certain DSM programs, but is unable to verify the esti-

mate.<sup>11</sup> The regulator also must be able to verify that the utility has carried out the program. DSM information programs are often cited as programs of this type. Such programs disseminate information through the media or through energy audits at individual sites. Regulators may believe that they have a rough but unbiased estimate of the savings that will result from these information programs and this may lead them to conclude that such programs are cost effective. However, it may be very costly or impossible to verify that the programs have resulted in energy savings and societal benefits. This makes it impossible to base an incentive mechanism on measured net benefit. The only possibility is for the regulator to write what economists call a forcing contract, where the utility is instructed to take a particular action (the informational program) and is given a reward for doing it, or a penalty for not doing it, that is sufficient to insure that it will be done. A markup incentive mechanism is a type of 'forcing contract.' It specifies how much is to be spent and how it should be spent, and promises that the costs and a specified markup (e.g. 5%) will be reimbursed.

Markup programs present a significant danger of inefficiency because the stringent informational assumptions detailed above are often not met. When the regulator has difficulty observing the utility's actions, it will reward the utility only for costs incurred and not for actions taken. In such cases, the utility will have an incentive to act perversely. For example, the utility might turn a DSM education program into a thinly veiled public relations campaign. A second danger is the inability to verify publicly the regulator's private estimate of net benefit.

<sup>9</sup> See, for example, Herman (1994), Braithwait and Caves (1994), and Hobbs (1991).

<sup>10</sup> Eto et al. (1996b), recently examined the measurement and evaluation costs for 12 large commercial lighting programs and found these costs to average less than 3% of total utility costs.

<sup>11</sup> An unbiased estimate is not necessarily easy to come by. In fact, in the circumstances in which a markup is useful the regulator will probably have to take it on faith alone that the estimate is unbiased. Nevertheless, the regulator may believe this, and wish to act on it.

### 3.4. Hybrid incentives reflect multiple regulatory objectives

Hybrid incentives are incentive formulas that combine two or more of the three basic incentive designs. Both MECo and PGE have hybrid incentives (see Table 2). MECo's incentive mechanism combines a bonus and a shared-savings incentive mechanism and adjusts the incentive level based upon actual spending levels. The bonus incentive mechanism for 1994 provides \$1.53/kW and 0.11¢/kWh for savings that exceed 50 percent of the forecasted or expected level. The shared-savings incentive mechanism applies if the net benefits of the program are positive and simplifies to roughly 1.4 percent (after tax) of net benefits.

PGE's hybrid incentive mechanism combines a shared-savings incentive mechanism for two types of net benefits and a bonus incentive mechanism. The incentive payment, in simplified form, equals 10 percent of the net benefits using only utility costs, 10 percent of the net benefits using the total resource costs, and 5 percent of the avoided cost benefits.<sup>12</sup> The PGE incentive, therefore, combines three regulatory objectives: net benefits (shared savings with a TRC perspective), rate impacts (shared savings with a utility cost or UC perspective), and energy savings (bonus).

Hybrid incentive mechanisms reflect a regulatory preference that the utility pursue multiple objectives through its DSM programs. It is instructive to consider two situations: (1) there are multiple objectives for the entire DSM portfolio; and (2) there are different objectives for individual DSM programs within the portfolio.

In the first case (multiple objectives for entire portfolio), it is straightforward to show algebraically the resulting weight or importance given to each objective. The challenge lies in ensuring that the objectives are legitimate and that the weighting accurately reflects regulatory preferences among them. For example, the inclusion of a specific incentive to minimize rate impacts in PGE's incentive is a clearly separable regulatory objective from that of maximizing net benefits. But are they equally important to one another? Welfare economists would hold that rate impacts can be evaluated on a consistent basis with DSM net benefits, at least theoretically. Implementation of these approaches are, however, controversial, as was discussed in measuring elements of net benefits. This is clearly an area in which individual commission preferences will vary. What is important is that these preferences are clearly communicated.

<sup>12</sup> Utility costs include utility program costs and utility rebate costs, and total resource costs include these costs as well as incremental participant costs.

## 4. Principles for establishing incentive payments

Table 1 summarizes 1992 incentive payments and DSM expenditures for the ten utilities in our sample. We find that some of the incentive mechanisms have been highly profitable; New York State Electric and Gas (NYSEG) and PGE earned returns of 40 and 94 percent,<sup>13</sup> respectively, on their DSM expenditures in 1992. These high returns contrast sharply with the low returns earned by Southern California Edison (SCE), 2%, Northern States Power (NSP), 3%, and APS, 9%.

In Table 4, we present forecasted or expected shared-savings incentive payments for more recent program years (i.e., 1993 and 1994), and omit markup incentive payments and utilities with bonus incentive mechanisms. We have also calculated the ratio of expected incentive payments to expected utility expenditures, as well as the ratio of expected incentive payments to expected Total Resource Cost net benefits.<sup>14</sup> For these calculations, we consider only the expenditures and net benefits associated with the shared savings programs.

The shared savings programs examined in Table 4 are also fairly profitable. Jersey Central Power and Light (JCP&L) and PGE were expected to receive returns of about 34 and 50 percent, respectively. At the same time, JCP&L was also expected to undertake an equally large 'core' program for which it was to receive no incentive and PGE's incentive payments were subject to measurement and verification studies that continue for the life of the measures. For the remaining utilities, incentive payments were expected to comprise less than 20 percent of utility expenditures. In addition, we find that the incentives account for between 8 (SCE) and 27 percent (Con Edison) of the TRC net benefits of the utilities' DSM programs.

### 4.1. The crucial role of unobservable (hidden) costs

To begin, we note that the purpose of an incentive mechanism should not be to reward the utility, but to induce it to achieve regulatory objectives. This can be forgotten, and the 'shared-savings incentive' can inappropriately come to be thought of as merely a plan for

<sup>13</sup> Incentive payments made to PGE, however, are contingent upon ex-post measurement and evaluation, which utility staff indicate will likely reduce the incentive payment.

<sup>14</sup> We define Total Resource Cost net benefits as the avoided cost benefits less utility administrative costs (including measurement and evaluation costs), utility rebate or incentive costs, and incremental customer costs for the shared savings program. We have not included the benefits resulting from avoided environmental externalities, nor have we included shareholder incentive payments. Utility administrative and rebate expenditures were readily available, but customer costs were more difficult to obtain. For Con Edison and NYSEG, we extrapolated customer cost figures from Utility Cost test and Total Resource Cost test ratios. See Stoft et al. (1995).

Table 4  
1993 and 1994 forecasted shared savings shareholder incentives (\$million)

Utility	State	Expected shareholder incentives before taxes millions \$)	Incentive/DSM expenditure (%)	Incentive/TRC net benefit** (%)
PG&E, 1994	CA	12.4	15.8%	16.8%
SCE, 1994	CA	5.5	9.2%	8.0%
MECo, 1994	MA	7.2	10.4%	14.8%
JCP&L, 1993	NJ	4.2	33.8%	—
Con Edison, 1994	NY	24.7	19.6%	27.1%
NYSEG, 1994	NY	3.4	8.2%	13.9%
PGE, 1993	OR	8.9	50.3%	23.1%

\*\* See Footnote 14 for definition of net benefit.

providing the utility with an opportunity to share the spoils between customers and shareholders. This may be its outcome but it is not its purpose. Nevertheless, it may not be possible to maximize social welfare without also making the utility better off.

The economic theory of incentives has been developed using the principal-agent model (see, for example, Laffont and Tirole, 1993). In this model, the principal rewards the agent according to some formula based on observations regarding the agent and its situation. Applied to utility DSM programs, the principal is the regulator, and its agent is the utility. When the principal (regulator) has perfect information about the agent's (utility's) costs and actions, a simple 'forcing contract' works perfectly. This simply specifies exactly what the utility must accomplish in order to obtain the reward. Markups are essentially forcing contracts. However, when the utility has useful private information (i.e., when the utility knows more about DSM than the regulator), an optimal contract always leaves the utility with some choice. This choice allows the utility to make use of its information in a way that is beneficial to both parties, and the incentive contract motivates the utility to do so.

To see the importance of unobservable costs, consider how a utility would react to a very weak incentive that was proportional to net benefit. Assume that an incentive mechanism pays the utility one percent of net benefits, and that all of the utility's DSM program costs are reimbursed and net lost revenues are compensated. Conventional wisdom suggests that, despite this, an incentive payment of only one percent would be too small to induce a utility to pursue a large DSM program. Yet, with all expenses reimbursed and net lost revenue recovered, any incentive payment at all should increase the utility's profit level. On a \$100 million DSM program with a net benefit/expense ratio of 1.5, the utility would earn \$1.5 million for its shareholders. This is not a large sum of money, but there is no apparent reason for utility managers to ignore it.

We say 'no apparent reason' because our review of

current practice suggests that no utility would be motivated by the one percent incentive and we assume that, therefore, utilities have reasons to ignore it. Apparently the public utility commissions (e.g., those in NY, CA, NY, and OR), which have set incentives rates ten to twenty times higher than this, also believe that small incentives would be ignored. One can only assume from this behavior that regulators believe the utility incurs additional costs, which are not apparent to regulators outside the utility and are thus not reimbursed. The issue to which we now turn is what are these costs.

#### 4.2. Defining and measuring hidden costs

We have asserted that a fair incentive must mitigate a utility's hidden costs. However, as indicated by their name, hidden costs are difficult to measure. In this section, we develop a classification scheme for hidden costs to identify considerations for establishing incentive payments.

We believe it is useful to distinguish two types of hidden costs and relate them explicitly to the lifecycle of DSM programs. The first type of hidden cost consists of the very real management costs associated with the additional effort and organizational changes required to implement successful programs. There are internal costs associated with managerial effort by those not directly on the DSM program payroll, with the disruption of starting new programs, and with the transfer of talented managers away from other important tasks. These costs are rarely discussed and difficult to measure. We suspect these costs will be greatest in the early phases of DSM program implementation. These costs are reflected in the shape of the hidden cost curve, which is taken up in the next section.

The second type of hidden cost consists of the opportunity costs associated with utility activities foregone by pursuit of DSM programs. Opportunity costs include both uncompensated net lost revenues caused by DSM programs and foregone earnings from alternative supply investments that would have been made in the absence



of a DSM program. We believe these costs increase with the scale of DSM programs and, therefore, will be greatest in the later phases of DSM program implementation.

This second type of hidden cost, while still difficult to measure, is more well-defined conceptually than the first type of hidden cost. The primary analytic issue is determining earnings comparable to those that would have been earned through the acquisition of resources in lieu of DSM. The issue is complicated because the profitability of alternatives depends on the riskiness of the alternatives and prevailing regulatory practices. For example, purchase power costs are generally passed through fuel adjustment clauses with limited regulatory review and earn no profit. Capital investments are rate-based and earned a profit based on the regulated rate of return. The profitability of these investments should in principle be captured by considering the Averch-Johnson effect.<sup>15</sup> In the present context, the Averch-Johnson effect holds that the regulated firm will choose to invest in capital plant whenever the cost of capital is less than the rate of return because doing so will provide a positive return to shareholders. Nevertheless, no utility is guaranteed that all capital will be entered into the rate base, or that the plant will operate as planned. In other words, risk considerations underlie all resource alternatives and differ substantially for different resources. Thus, in practice, establishing truly comparable earning levels is difficult.

Some commissions have recognized these opportunity cost issues explicitly in establishing incentive payments. For example, at one point California utilities were directed to multiply the rate of return on a supply side investment by the DSM program costs to determine target incentive levels following an interim rule adopted by the California Public Utilities Commission (CPUC), which indicated that the ‘shareholder’s rate of return on DSM programs should be no greater (and could be lower) than shareholder’s rate of return on utility-constructed power plants.’<sup>16</sup> The California approach further acknowledged that the comparative risks associated with earnings from utility-constructed power plants should be considered when compared to the earnings from DSM programs that displace the need for these plants.

#### 4.3. Review of recent trends in establishing incentive payments

We return now to our review of recent practice to provide some insight into the magnitude of hidden costs and

to at least bound the range of incentive payments. On the low end, SCE and NSP earned incentive payments that represented only two and three percent of expenditures in 1992, respectively (see Table 1). Despite these comparatively meager rewards, the utilities undertook their DSM programs, although not without complaint.<sup>17</sup> At the same time, the trend for these utilities has been to increase their incentives. The CPUC recently increased the share of net benefits to 30% for all of the California utilities, and NSP recently filed a request to change its incentive mechanism and to increase the expected reward to about 5% of net benefits.

On the high end, incentive levels also appear to be coming down over time. In 1992, the New York and New Jersey utilities in our sample received rewards in excess of 25 percent of their DSM expenditures and PGE could receive a reward up to 94 percent (depending upon on-going monitoring and evaluation). See Table 1. For more recent program years, the incentive rates for some of these utilities have come down. For example, the New York Public Service Commission recently reduced the NYSEG’s after-tax share of net benefits from 15% to 5%.

### 5. The importance of marginal incentive rates

Public utility commissions, utilities, and public interest groups continue to debate the appropriate design for DSM shareholder incentive mechanisms. For example, in a recent California proceeding, parties recommended complex, discontinuous shared-savings incentive functions as well as straight-line incentive functions, many with different marginal incentive rates and target incentive levels for different DSM programs. To put this issue in context, we compare marginal incentive rates for seven shared-savings incentive mechanisms that were in place for the 1994 program year.<sup>18</sup>

Fig. 2 summarizes the seven shareholder incentive mechanisms graphically; the slope associated with each incentive mechanism is the marginal incentive rates (i.e., the additional incentive achieved for an additional dollar in net benefits). Fig. 2 expresses the incentive payment as a function of a forecasted expected level of net benefits. This form of presentation normalizes some of the differences in DSM program size between utilities. It is important to bear in mind that the shareholder incentive

<sup>15</sup> See Train (1991), for a good discussion of the Averch-Johnson effect.

<sup>16</sup> However, the CPUC is currently reconsidering the appropriate target incentive level and other related issues, and has issued a preliminary decision allowing California utilities to retain 30% of net benefits beyond certain threshold levels (CPUC, 1994b).

<sup>17</sup> A successful incentive need not be a fair incentive in that a successful incentive can motivate utility behavior, yet not fully compensate the utility for its hidden costs.

<sup>18</sup> In some cases, the incentive depends upon post-program evaluations which have not yet been completed (e.g., Midwest) and, in the case of JCP and L, the 1994 thresholds, targets, and other program details were unavailable. In these instances, we look at earlier program years.

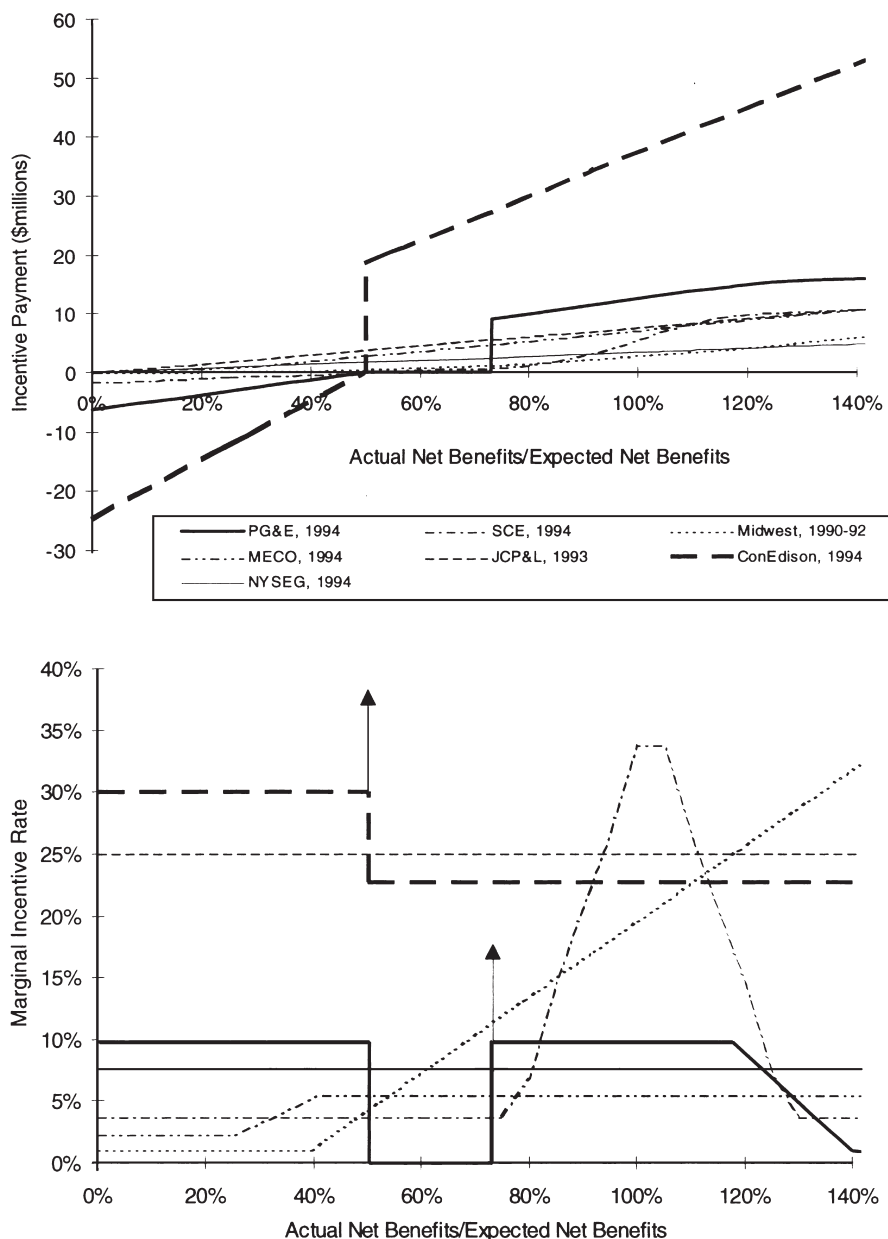


Fig. 2. Incentive payments and marginal incentive rates as a function of percentage of expected net benefits achieved for seven shared savings mechanisms.

mechanisms for these utilities are not strictly comparable because utilities use different definitions of net benefits (see Section 3).

JCP&L and Con Edison consistently have the highest incentive rates across various net benefit ranges. JCP&L earns \$0.25 for each additional \$1 of net benefit achieved and Con Edison earns \$0.23 to \$0.30 for each additional \$1 of net benefit.

SCE's incentive mechanism displays the most variability in marginal incentive rates, with the highest rate occurring at 100 percent of forecasted net benefits. PG&E has the most complex mechanism in terms of varying marginal incentive rates. Penalties are imposed below 50

percent of forecasted net benefits; the marginal incentive rate is 0 percent and infinity between 50 and 75 percent of forecasted net benefits, 10 percent between 75 and 120 percent, decreasing down to one percent at 140 percent of forecasted net benefits.

For purposes of simplicity and clarity, we have aggregated the incentive mechanisms of PG&E and SCE in Fig. 2. In reality, the incentive functions differ for the various utility programs (e.g., residential new construction, commercial energy efficiency incentives) and, at least for SCE, the marginal incentive rates vary dramatically (see Section 5.2, below).

### 5.1. Marginal incentive rates determine performance

Our review of current practice suggests that there is substantial variation in marginal incentive rates. We believe this variation results in part from an insufficient appreciation of the role marginal incentive rates can play in signaling the desirability of a particular level of utility performance.

In the previous chapter, we introduced the concept of hidden costs as a basis for establishing incentive payments. We now consider how hidden costs might change as a function of net benefits. Fig. 3 presents a hypothetical hidden cost curve for a utility and two incentive functions, each with different marginal incentive rates (i.e., different slopes). For any level of performance, profit (or loss) to the utility is measured by the difference between the incentive line and the hidden cost curve. A profit-maximizing utility will choose a level of performance that maximizes the vertical distance (i.e., profit) between the incentive function and the hidden cost curve.<sup>19</sup> This profit maximizing point occurs where the slope of the hidden cost function equals the marginal incentive rate.

This line of reasoning suggests that dead-bands are inappropriate. The marginal incentive rate within a dead-band is zero but rises to infinity at the upper end of the dead-band. (See, for example, PG&E's marginal incentive rate in Fig. 2.) Consequently, dead-bands provide no incentives for utilities to increase net benefits within the dead-band region, but significant (literally, infinite) incentives to move across to the upper-end of this region.

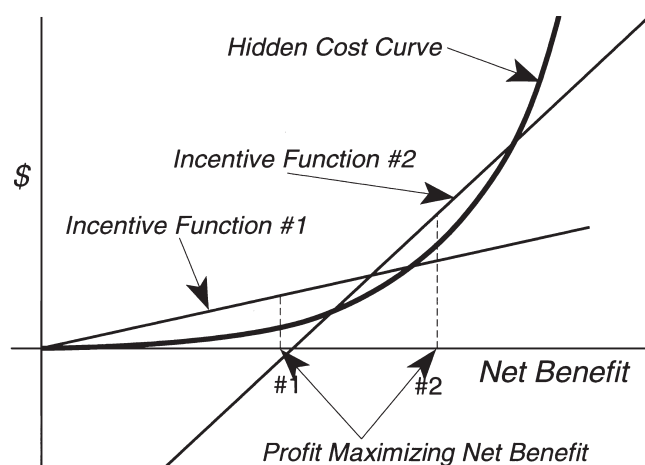


Fig. 3. Performance depends upon the marginal incentive rate as well as the hidden cost curve.

<sup>19</sup> Recall that the basic rationale for offering any incentive is to provide an opportunity for a utility to trade off society's observable net benefits against its own hidden costs. In the current context, the marginal incentive rate will signal the utility to incur hidden costs up to the point where the difference between observable net benefits and hidden costs is maximized.

The message sent is that the regulator is indifferent to any level of performance within the dead-band region.

Fig. 4 shows that the utility's performance level depends only on the slope or marginal incentive rate and not whether hidden costs are covered. The first incentive mechanism, which does not cover hidden costs for any level of net benefit, will induce the utility to minimize its losses. This is the same level of performance that will result from the second incentive mechanism, but, in this second case, the utility will be maximizing profit, not minimizing losses.

### 5.2. A recent example of a marginal incentive rate that was too high

The importance of the marginal incentive rate is underscored by SCE's performance in 1993. While we aggregated SCE's shared savings mechanisms into one mechanism for simplicity earlier, SCE has separate shared-savings incentive mechanisms for each of seven individual DSM programs. Fig. 5 illustrates that the marginal incentive rates for the residential new construction, non-residential new construction, direct assistance, and residential appliance efficiency programs are extremely high: for each additional \$1 in net benefits achieved, the utility receives a correspondingly high incremental incentive payment.

In fact, the marginal incentive rates vary from 6015 to nearly 55 000 percent for the residential new construction program, and from 191 to nearly 2000 percent for the nonresidential new construction program. In other words, for the residential new construction program, SCE would receive from \$60 to \$550 for each additional \$1 in net benefits!

Not surprisingly, the marginal incentive rates had the expected effect and SCE far exceeded its expected performance in 1993, particularly for those programs with high marginal incentive rates. For its residential new

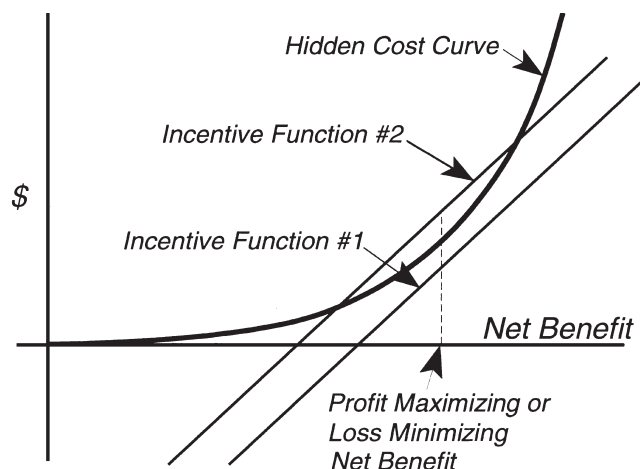


Fig. 4. Performance level depends upon the marginal incentive rate, not whether hidden costs are covered.

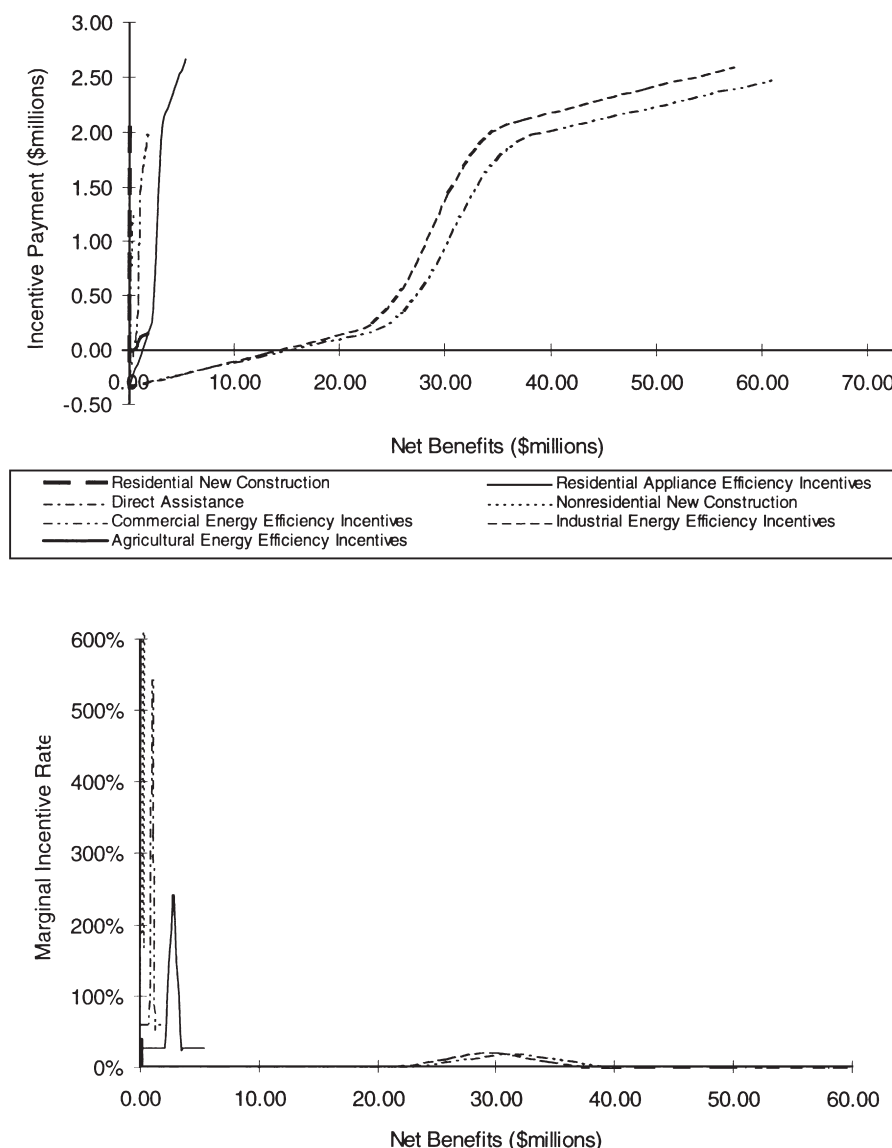


Fig. 5. Edison's 1993 incentive payments and marginal incentive rates as a function of the net benefits achieved.

construction, SCE had forecast \$4000 in net benefits, but achieved \$575 000. In the non-residential construction program, SCE far exceeded its goal of \$173 000 and achieved \$10 973 000 in net benefits. As a result, SCE filed for a \$66 million incentive payment, which far exceeded the forecasted incentive payment of \$5.1 million.<sup>20</sup>

Clearly, SCE's performance was in large measure tied up with its forecasted performance targets that, in retrospect, turned out to be quite modest; although we cannot say with certainty whether these were the result of an upturn in the business cycle, the result of aggressive marketing by the utility (in 1993, Southern California was in an economic recession) or accounting conven-

tions that led to the inclusion of installations started in the 1992 program year in 1993 program year totals. What is important is that an incentive to low-ball these forecasts was implicitly created by the high marginal incentives offered.

### 5.3. Decoupling marginal incentive rates from the total incentive payment

The very high marginal incentive rates we recommend are at odds with conventional wisdom because they suggest that net transfers to shareholders may be very high. But the incentive mechanism described in the previous sections need not result in large transfers of funds from ratepayers to stockholders. Introduction of a fixed charge, *F*, allows the regulator to decouple the total incentive paid from the marginal incentive rate. Concep-

<sup>20</sup> In a subsequent settlement with CPUC/DRA, SCE reduced its earnings claim to \$17 million (CPUC, 1994a).



tually, introduction of a fixed charge can be thought of as moving the marginal incentive rate curve up or down. See Fig. 1.

In principle, the utility could be assessed a fixed charge equal to the expected value of net benefit and the incentive payment would be zero for this expected level of performance. This would not disturb its incentive properties, yet would avoid large transfers of income to the utility. However, we recommend that the expected net transfer to the utility should exactly equal  $H$ , the utility's hidden costs (see Section 4).

Decoupling marginal incentive rates from the total incentive payment also allows us to formally introduce the use of penalties for sub-par performance and performance thresholds. In the case of penalties, the introduction of a fixed charge represents a penalty to the utility at zero level of net benefit, which then decreases to zero at some positive level of net benefit (i.e., the marginal incentive crosses the horizontal axis of zero incentive payment). A performance threshold can be thought of as a zero marginal incentive below the threshold (expressed as a particular level of net benefit).

Implementing high marginal incentives rates increases the range of payments and, through the use of a fixed charge, the penalties that a utility may incur. A larger range of total payments translates to increased earnings volatility to the utility and is therefore risky. Tying a large range of total payments directly to performance, on the other hand, reduces risks to regulators of paying for benefits not received. In the next section, we turn to the use of other incentive design features to mitigate these risks both to the utility and to the regulator.

## 6. Mitigating risk with earnings and penalty caps

Earnings caps and decreasing marginal incentive rates are two ways that regulators limit the risk of 'paying too much' for the DSM programs. This might occur, for example, if a utility substantially under forecasts estimated net benefits. Among the eight utility shared-savings incentive mechanisms examined for this paper, however, only NYSEG has explicit earnings caps that limit total incentive payments (see Table 5). At the same time, most of the programs have *de facto* earnings caps due to spending limits and decreasing marginal incentive rates above a certain level of forecasted net benefits. For example, PG&E is limited to 130 percent of its approved budget and has a marginal incentive rate that decreases above 140 percent of the expected net benefits for each of its shared-savings program categories.

However, as described in Section 5, the spending restrictions and decreasing marginal incentive rates did not work as a *de facto* earnings cap for SCE. SCE was able to file for incentive payments 10 times larger than forecasted due to a combination of above-forecast per-

formance and extremely high marginal incentive rates for its new construction programs. Examination of SCE's incentives suggests that the very formulation of this highly complicated incentive made it difficult to determine the resulting marginal incentive mechanism until it was too late. SCE's experience is just one example of the unforeseen risks that arise when relying on untested and relatively complicated incentive mechanisms. The recognition that some risk is inevitable in all incentive mechanisms provides a strong motivation for limiting the total amount payable or the penalties assessed in the design of the incentives.

### 6.1. What are the risks associated with DSM shareholder incentives?

The use of incentives to motivate utility behavior is not risk free. For utilities, risks manifest themselves as increases in earnings volatility. For regulators, too, there are risks associated with paying too much for DSM, as well as political risks that arise from incentives which do not achieve desired outcomes. It is instructive to characterize these risks more precisely before considering the ways in which they may be mitigated.

For the utility, the risks associated with DSM shareholder incentives can be expressed by considering how the incentive design affects the total incentive payment. From this perspective, an incentive design that causes the total incentive payment to vary more than another design is more risky. Hence, for a given total incentive payment, a risk averse utility will favor the smallest possible marginal incentive rate. In the extreme, a risk averse utility will prefer a marginal incentive rate of zero, meaning that there is no risk of any deviation from some expected incentive payment.

For regulators, there are two risks: First, there is the risk of paying too much for DSM. Second, there are political risks associated with large transfers from ratepayers to shareholders.

With respect to the first type of risk, the regulator is concerned with both the true net benefits and the incentive payment. The question is to what extent the incentive payment should count as a negative. If the regulator adopts a version of the ratepayer's perspective, the entire incentive payment should be subtracted from true net benefit, while if the regulator adopts a societal perspective, then none of the incentive payment should be subtracted.

With respect to the second type of risk, we must also acknowledge psychology and politics. It may be politically risky for the regulator to allow an outcome where both the net benefit and incentive payment are \$50 million greater than expected. As we shall discuss, no one should be disappointed with such an outcome, but human psychology being what it is, ratepayers may become upset at such a large transfer to stockholders,

Table 5  
Earnings and spending caps for eight utility DSM programs

Utility, program year	State	Type of mechanism	Earnings cap?	Decreasing marginal incentive rate?	Spending cap?
PG&E, 1994	CA	Shared savings	no	decreases above 140% of expected net benefits	130% of the approved budget
SCE, 1994	CA	Shared savings	no	decreases above 125% of expected net benefits	100% of the approved budget
Midwest, 1990-92	IA	Shared savings	no	no	yes
MECo, 1994	MA	Shared savings/bonus	no	no	yes
JCP&L, 1993	NJ	Shared savings	no	no	yes
Con Edison, 1994	NY	Shared savings	no	no	yes
NYSEG, 1994	NY	Shared savings	75 basis points, ~ \$16.5 million	no	no
PGE, 1993	OR	Shared savings/bonus	no	no	de facto cap

and this may present a danger to the regulator. In this case, the regulator may have a politically-based risk aversion to large deviations from the expected incentive payment.

## 6.2. Addressing risk aversion by tailoring incentive designs

We now consider modifications to the simple linear incentive that can mitigate both of these problems. This time, instead of dividing the analysis between regulator and utility, we will distinguish between high performance and low performance.

The case of high performance is straightforward. If net benefits are higher than expected, this will present no problem for the utility since high net benefits simply result in higher incentive payments. At first glance, the regulator should also be supportive, provided the incentive design rewards net social benefits. In this situation, the additional net benefits achieved by the utility also constitute net benefits to society at large.

The regulator, however, may face political problems. Although in an economic sense the program has been more successful than anticipated, the regulator may be faulted for not anticipating the outcome and, consequently, over-rewarding the utility. To prevent such a surprise outcome, the regulator can simply put a cap on incentive payments or drastically limit the marginal incentive (and, thus, the total incentive payment) in the high performance region. This ensures that the utility has little incentive to perform much better than expected and avoids causing political embarrassment for the regulators. In the very unlikely event that the utility performs exceptionally well in spite of the earnings cap, the incentive payment will be held down by the cap, and the regulator will have secured a very 'good deal' for the ratepayers.

Having addressed 'upside' risk by discouraging

exceptional achievement through incentive caps, we turn our attention to the 'downside' risk. In fact, the downside case is the mirror image of the up-side case; however, we are this time concerned primarily with risk to the utility. In other words, assuming a marginal incentive rate of one, for the moment, underachievement by the utility presents no risk to ratepayers, since for every \$1 of expected net benefits that the utility fails to achieve, the ratepayers will be reimbursed by exactly \$1. Hence, as with the risk associated with high performance, the risk associated with low performance can simply be mitigated by a limit on incentive payments, but this time the limit is a floor and is likely to have a negative value. We refer to this as a penalty cap.

A strict penalty cap has a property that is of concern to the regulator. If the incentive mechanism has inadvertently been designed with such a low level of incentive that the utility deliberately chooses the penalty cap, it will always choose not to participate in DSM at all. This is because there is no incentive within that region to move towards higher levels of net benefit, and doing so inevitably imposes some hidden costs. Since an outcome of zero net benefit, even when compensated by a penalty payment, is a loss to ratepayers relative to any point on the 100 percent incentive line, the regulator may want to discourage this outcome. This can be done by replacing the cap with a reduced incentive region having a more traditional marginal incentive rate, say 15 percent. A 100 percent marginal incentive function with a 15 percent marginal incentive 'cap' is guaranteed to produce as least as much net benefit as the traditional straight-line incentive function with a lower marginal rate.

To summarize, it is easy to limit the regulator's up-side risk with an earnings cap, and to limit the utility's down-side risk with a penalty cap. The magnitude of these risks increases with higher marginal incentive rates. Regulators should recognize, however, that an earnings cap removes incentives for extraordinary per-

Table 6  
Summary of recommendations for the design of DSM shareholder incentives

Shareholder incentive design issue	Recommendation
DSM resource programs	Apply shared-savings incentives to DSM resource programs
DSM information programs	Use separate incentives for individual programs only when net benefits are difficult to measure, but are known to be positive
Expected incentive payment	Set expected incentive payments based on covering a utility's 'hidden costs,' which include some transitional management and risk-adjusted, opportunity costs
Marginal incentive rate	Use higher marginal incentive rates than are currently found in practice, but limit total incentive payments by adding a fixed charge
Regulatory risk mitigation	Mitigate regulator's over-payment risks from under-forecasting by lowering the marginal incentive rate for high performance levels
Utility risk mitigation	Mitigate earnings risks to utilities by lowering the marginal incentive rate for low performance levels

formance, while a penalty cap can impose some risk on the utility and the regulator. The latter problem can be reduced by using a very moderately sloped incentive region in place of a strict penalty cap.

## 7. Summary and concluding thoughts

We have reviewed recent DSM shareholder incentive designs and utility performance to investigate several key design issues for DSM shareholder incentives, including: (1) the appropriate quantity to reward (e.g., net benefits, saved energy, or monies spent); (2) considerations for establishing the expected incentive payment; (3) the importance of, and optimal value for marginal incentive rates; (4) the role of earnings and penalty caps to mitigate risks to both the utility and the regulator; and (5) the justifications for aggregate versus separate incentive mechanisms. Our design recommendations are summarized in Table 6.

Examination of utility DSM shareholder incentives provides regulators with a unique opportunity to evaluate the effectiveness of a particular type of targeted incentive regulation designed to motivate utilities to achieve a specific regulatory objectives. We observe that current mechanisms can probably be improved by harnessing their incentive powers more deliberately to ensure better alignment of regulatory objectives and utility financial self-interest. Better alignment reduces adversarial confrontation and eliminates the need for regulatory micro-management.

As regulators contemplate other applications of incentive regulation, the lessons from DSM shareholder incentives are clear. Be explicit about the regulatory objective; then, when considering multiple objectives, look broadly at alternatives that have the potential to meet these objectives without compromising the incentive properties of the mechanisms.

## Acknowledgements

The work described in this study was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Utility Technologies of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

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